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PHASOR MEASUREMENT UNITS

Gray Davis, Governor



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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliability energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Commission), annually awards up to \$62 million through the Year 2001 to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/ Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally-Preferred Advanced Generation
- Energy-Related Environmental Research
- Strategic Energy Research.

In 1998, the Commission awarded approximately \$17 million to 39 separate transition RD&D projects covering the five PIER subject areas. These projects were selected to preserve the benefits of the most promising ongoing public interest RD&D efforts conducted by investor-owned utilities prior to the onset of electricity restructuring.

Edison Technology Solutions (ETS) is an unregulated subsidiary of Edison International and an affiliate of Southern California Edison Company (SCE). As a result of a corporate restructuring, ETS ceased active operations on September 30, 1999. ETS' remaining rights and obligations were subsequently transferred to SCE.

What follows is the final report for the Phasor Measurement Units, 1 of 10 projects conducted by ETS. This project contributes to the Strategic Energy Research Program program.

For more information on the PIER Program, please visit the Commission's Web site at: <http://www.energy.ca.gov/research/index.html> or contact the Commission's Publications Unit at 916-654-5200.

Executive Summary

The goal of this Energy Technology Solutions (ETS)-managed project was to develop a system to facilitate real-time monitoring of electricity transmission and distribution facilities. This monitoring system supports the Public Interest Energy Research (PIER) objective of improving the reliability of California's electricity.

Phasor Measurement Units (PMUs) monitor phasor quantities (magnitude and phase angle) of voltage and the current of electrical power system. ETS installed PMUs in the Western Systems Coordinating Council (WSCC) Extra High Voltage (EHV) grid to monitor the system states. The PMUs send data to a central computer, called the Phasor Data Concentrator (PDC), via a high-speed communications line. PMUs provided useful data for the post-disturbance analysis of the August 1996 WSCC system disturbance. Data collection and archiving was not automated at that time.

Project Objectives

The objectives of this project were to:

- Install additional PMUs on the Southern California Edison (SCE) transmission grid
- Establish communications links between the PMUs and the PDC in Rosemead, California
- Develop software to allow accessing and viewing of archived PMU data from desktop computers
- Develop software to allow viewing of real-time PMU data from desktop computers
- Establish interutility communication between the Bonneville Power Administration (BPA) and the SCE PDC
- Develop software to allow the exchange of phasor data between the SCE and BPA PDCs.

Methods

SCE, a subcontractor to ETS, installed two PMUs at two critical substations, the Mohave 500 kilovolts (kV) and the Kramer 230 kV in the SCE EHV grid. SCE established high-speed communications links between each PMU and the PDC at their headquarters in Rosemead, California.

We developed the software program, Disturbance File Reader that allowed the end user to view the archived PMU data available on the PDC. System protection engineers and other utility personnel can view the data at their computers. The program converts and stores data files in other data formats for future analysis.

PDC Data Streamer, the second software program developed, allowed the end user to view the PMU data in real time and provided continuous data recording capability. The project also provided an analog communications link between SCE's PDC and BPA PDC located in Portland, Oregon. Using this communications link, BPA and SCE exchanged PMU data.

The project demonstrated the PMU data exchange concept using an analog communications link. BPA and ETS co-developed a PDC data exchange protocol that was tested, with positive results.

Project Outcomes

The following outcomes were achieved:

- Installed two PMUs, one at the Mohave substation and one at the Kramer substation.
- Established communications links between the PMUs and the PDC in Rosemead, California.
- Developed a software program for accessing and viewing archived PMU data from desktop computers.
- Developed a software program for real-time viewing of PMU data from desktop computers.
- Established an analog communication link between the BPA and SCE PDCs.
- Developed software that allowed the exchange of phasor data between the SCE and BPA PDCs.

Benefits to California

This project represents an important step toward improving the reliability of California's electricity and transmission-owning utilities. By facilitating real-time monitoring of electrical transmission and distribution systems, it allows the California Independent System Operators (CAISO) to monitor the voltage magnitudes and phase angles continuously from the substations where the PMUs are installed.

Real-time information is crucial for operators of the regional grid and CAISO. Continuous display of phasor information can be used to predict system stability in the event of a disturbance. Data exchange could also enable access to information from distant locations before changes are detected in local measurements.

Conclusions

- Data exchange could provide significant information on system state from distant locations before changes are detected through local measurements.
- Future system developments would enable the use of PMU data for on-line applications such as load flow, stability, state estimation, and to develop real-time nomograms, all of which would further enhance system reliability.

Recommendations

- To facilitate the installation of PMUs and PDCs by more companies, current users should publish and share technical information and benefits.
- The feasibility of using commercially available hardware and software for PMU applications should be explored.
- Future research should focus on determining the real-time data exchange needs, the communications media requirement, and emergency communications links between PMUs and PDCs.

Abstract

The goal of this Edison Technology Solutions (ETS)-managed project was to develop a system to facilitate real-time monitoring of electricity transmission and distribution facilities. To achieve this goal, ETS installed two Phasor Measurement Units (PMUs) at the Mohave and Kramer substations in the Southern California Edison (SCE) system. The PMUs send data, via a high-speed communications line, to a central computer, called the Phasor Data Concentrator (PDC), a real-time data acquisition computer system located in Rosemead, California.

PMUs were installed to provide phasor information (both magnitude and phase angle) on the state of the interconnected grid system. This phasor information is used for post-disturbance analysis of the system. Disturbance Reader, a software program developed for this project, displays archived PMU data. With this software, the end-user can display and view archived PMU data on their desktop computers. In addition, the user can select previously archived PMU data from the PDC and use the information for post-disturbance analysis. Another software program developed, PDC Data Streamer, allows the real-time display of the PMU data on the desktop computer through a connection to the PDC. This display capability provides a real time snapshot of the system that enables system operators to predict system stability.

An interutility communications link was established between the Bonneville Power Administration (BPA) PDC and SCE's PDC. This interutility communications link provides a path for PMU data exchange between BPA and SCE. The interutility PMU data exchange can be used following a disturbance to understand what occurred within the system.

1.0 Introduction

Phasor Measurement Units (PMUs) were developed in the early 1980s to monitor the system states of power transmission grids. These devices provide a precisely synchronized set of measurements of power system states when a major disturbance of the Western Region Extra High Voltage (EHV) transmission system occurs. These devices have a significant impact on several aspects of power system reliability, real-time monitoring, state estimation, and system protection and control.

Approximately 33 PMUs are installed in Western System Coordinating Council (WSCC) member systems (Bonneville Power Administration (BPA), Southern California Edison (SCE), Pacific Gas and Electric (PG&E), Los Angeles Department of Water and Power (LADWP), Western Area Power Administration, Arizona Public Service (APS), Salt River Project, and B.C. Hydro). Most of these PMUs are currently in operation.

The PMUs send data to a data concentrator, typically a desktop computer system with real-time data handling capability. This data concentrator is called the Phasor Data Concentrator (PDC).

1.1 Need for the Technology

Before the advent of this California Energy Commission-funded project, managed by Edison Technology Solutions (ETS), improvements in regional power system reliability were difficult to achieve due to lack of communications lines and data exchange capabilities. Some utility companies had developed their own unique software to view the PMU data on their PDC, but data was not exchanged between various PDCs because each PDC operated individually, and was not interconnected.

Further, among current PMU users in the WSCC, different PDC systems are installed but, due to data format differences, they cannot exchange data among themselves even if a communications path exists between them. As a result, regional reliability improvements achievable through use of PMUs remain limited.

1.2 Project Objectives

The objectives of this project were to:

- Install additional PMUs on the SCE transmission grid
- Establish communications links between the PMUs and the PDC in Rosemead, California
- Develop software to allow accessing and viewing of archived PMU data from desktop computers
- Develop software to allow real-time viewing of PMU data from desktop computers
- Establish interutility communication between the BPA and the SCE PDC
- Develop software to allow the exchange of phasor data between the SCE and PBA PDCs.

1.3 Project Expenditures

The California Energy Commission approved funding of \$150,000 under the Commission's PIER transition funding program. Figure 1 provides a graphical depiction of the PMU project cash flow.

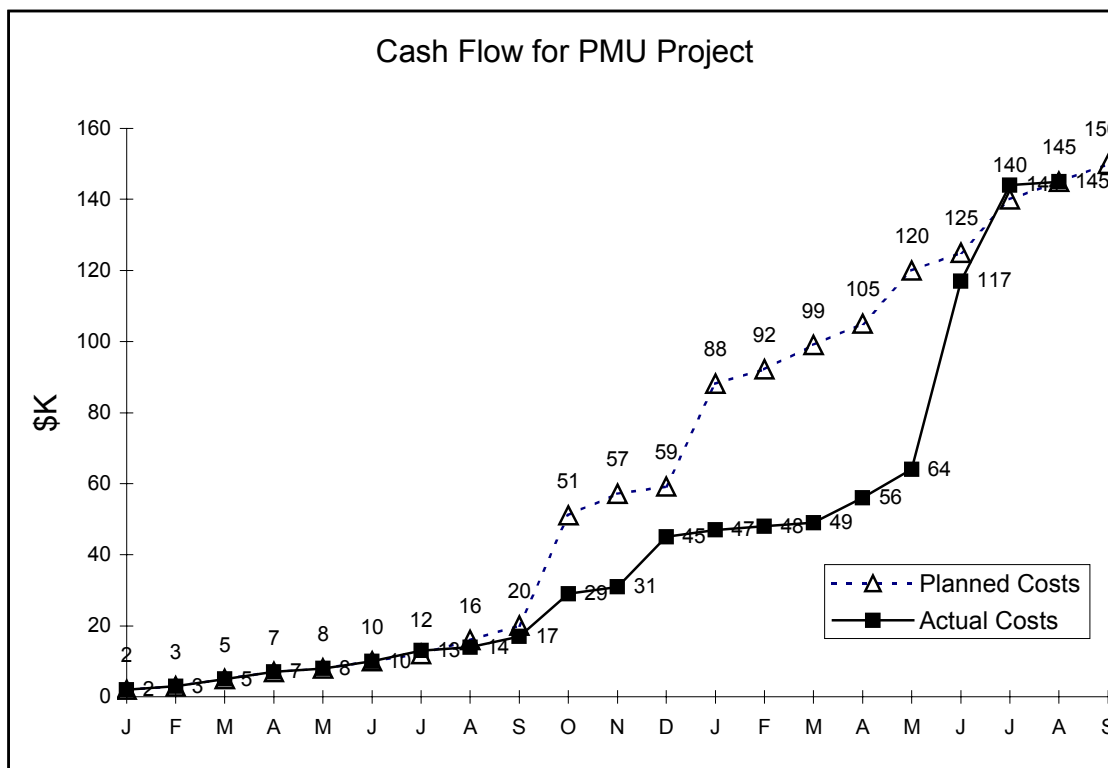


Figure 1. PMU Project Cash Flow (January 1998 through September 1999)

2.0 Technical Approach

This project achieved all of its objectives (Section 3.1). Details of how the results were achieved are also discussed. This section describes the development of each project element.

2.1 PMU Installation and Communications Links Between PMUs and the Rosemead PDC

ETS installed two PMUs and established communications links from PMUs to the PDC at Rosemead, California. SCE, as a subcontractor to ETS, provided the engineering, design, and installation of PMUs at the Mohave generating substation and the Kramer 230 kV substation. As part of this task, SCE also provided communications system design, installation, and testing.

The PMU at Mohave monitored the following phasors:

- Mohave 500 kV bus voltage
- Mohave Generator 1 line current at 500 kV
- Mohave Generator 2 line current at 500 kV
- Mohave-Lugo 500 kV line current
- Mohave-Eldorado 500 kV line current.

The PMU at Kramer substation was connected and provided the following signals:

- Kramer 230 kV bus voltage
- Kramer-Lugo #2 line current
- Kramer-Cool Water #2 line current
- Kramer-Lugo 115 kV line current
- Kramer-Victor 115 kV line current.

The communication link worked successfully and allowed the transmittal of PMU data from the two PMUs to the Rosemead PDC. (Appendix I, Section 1.1)

2.2 Software Development

ETS developed two software programs, the Disturbance File Reader and the Stream Reader. Both programs run on a personal computer (PC) running Windows 95 or NT. The PC requires at least 24 Megabytes (MB) of memory and an Ethernet port with full transmission control protocol and Internet protocol (TCP/IP) implementation. ETS developed both programs in the LabVIEW application.

2.2.1 Disturbance File Reader Program

The Disturbance File Reader allows users to retrieve data recorded during disturbances for viewing and analysis purposes. The Disturbance File Reader has the following functions:

- At startup, the program reads scaling factors for each PMU from a parameter file. Scaling factors are used for local display only.

- The program uses pushbuttons to access the PDC over Ethernet using TCP/IP protocols. It automatically downloads and displays the log file so that users can examine the disturbance file list.
- The user may select a file on the display and use a button to download the file.
- The program can display the following data types:
 - Phasor magnitude (voltage or current)
 - Phasor absolute phase angle (angle relative to Global Positioning System (GPS) time signals)
 - Phasor relative phase angle (angle relative to another phasor angle)
 - Frequency
 - Megawatts (MW)
 - Megavar (MVAR).
- The user can print the graph using the Print Screen option.
- After downloading the file, the user can convert the file to Mathematics Laboratory (MATLAB) or into American Standard Code for Information Interchange (ASCII) formats.

2.2.2 Stream Reader Program

The Stream Reader Program allows users to view real-time data coming from PMUs and create files in Disturbance Reader format for future use. The Stream Reader has the following functions:

- The operation starts with an initialization menu that allows users to set the IP port and address for the PDC data, disk drive, disk space, and directory settings.
- After initialization, the program reads the PDC data stream with its Ethernet port continuously until halted by a user. It will display up to five strip charts at a time. The program continuously records data on the disk using the same format used by the PDC for disturbance files.
- All the display functions can be altered by the user during program operation using point-and-click controls. Changing the scaling or type (quantity displayed) during the run does not interrupt data recording.
- A display-freeze button stops chart updating without interrupting data storage. When the display is restarted, it continues with current data.

The details of the software program and sample plots are shown in Appendix I, Section 1.2.

2.3 Installing the Communications Link between the PDCs

E2 Consulting Engineers, a subcontractor to ETS, coordinated with SCE, the LADWP, and the BPA to establish a communications link between the SCE PDC and the BPA PDC. They performed the following tasks:

- Installed two four-wire analog channels in the multiplex channel at an SCE site in Rosemead, California
- Exchanged test tones with LADWP to set channel levels
- Verified with LADWP that cross connects at LADWP were in place for the BPA circuit at Adel, Oregon
- Installed jumper connections from GO2 to GO3 circuits at a communications drop near the PDC
- Set levels with BPA technician and verified the circuit test
- Installed analog modems and tested with BPA to declare the circuit ready for service.

Appendix I, Section 1.3 provides the details how this communication link was established. This PDC-to-PDC communication link was used for interutility data exchange. The communication link was successful, as evidenced by the interutility PMU data exchange (discussed in the next section).

2.4 Interutility Data Exchange

The PDC exchange protocol sends data between two PDC units. The format is similar to the Institute of Electrical and Electronics Engineers (IEEE) format, but with modifications to provide for data from several PMUs rather than a single unit.

ETS and BPA defined and discussed the data exchange format via e-mail and at a meeting held in 1998. They further refined the format in early 1999 as the program was written. Appendix I, Section 1.4, Interutility Phasor Data Exchange, includes the complete protocol description.

The number of PMUs included in the data stream depends primarily on the communications bandwidth available. It is assumed that bandwidth is limited to standard channel capability. If it were unlimited, the full data stream could be exchanged using the streaming program.

Using the modem speed table, users choose the number of PMUs that fit into the exchange bandwidth, choose stations that are most significant in terms of system measurements, and then edit the configuration file to send the selected data. When the system is started, it reads the configuration files and runs the program.

The communications channel starts at BPA in Portland, Oregon on a long-wire connection to the BPA analog microwave transmitter. The BPA microwave transmitter connects to the Department of Water and Power (DWP) microwave transmitter in Southern Oregon.

At DWP headquarters, the signal is received and translated from the analog microwave to a digital format on the DWP digital microwave transmitter. It is then sent to Mt. Lukens in the San Gabriel Mountains. There it cross connects to SCE digital fiber optics and travels to the PDC at SCE in Rosemead, California. Data from SCE to the BPA travels the same path in reverse.

Initially, the system worked only intermittently. The long system traversing three utilities and many departments made testing coordination a challenge. Intermittent problems were first isolated to the BPA end wire connection. When this was resolved, the system was still intermittent. The problem was finally traced to a bad channel unit at the DWP and corrected.

In addition to communications, BPA found that the hardware interface on the PDC would not support the high data transmission rates required by this application. This interface had worked well for receiving data at a high rate but, due to its architecture, could not reliably support this high rate of data transmission. We resolved this by applying more advanced hardware. However, procurement lead times prevented upgrading the PDC system at SCE before the end of June.

The system ran successfully for a continuous period commencing on July 1, 1999. For the purposes of this report, statistics have been computed for the period of July 1, 1999 through July 5, 1999.

Overall, the link was highly effective. It operated accurately and reliably over the test period. It provides a dynamic system monitor for operations at both SCE and BPA system control centers. Further, it provides analysts with immediate access to system-wide information to facilitate timely problem analysis. Compared with most interutility data links that send data every few seconds to minutes, this system offers real-time dynamic wide area monitoring capability.

This test demonstrated that wide area exchange of phasor measurements could be made in real time with current technology and with acceptable reliability. It has been successful in establishing a data exchange link and demonstrating that it can run reliably and accurately.

Several improvements should be considered. The biggest limitation is the data communications link. The current analog link will exchange data from three stations each way. If typical patterns prevail, analog links are much more prone to dropouts and impairments requiring repair than are digital links. With a 56-kilobyte (KB) digital link, data from every station currently on SCE and BPA systems could be exchanged. This would give fairly comprehensive coverage of both systems, and a significant portion of the WSCC system would be visible to both utilities.

The PDC is capable of simultaneous data exchanges with several other PDC units. Additional PDC units at PG&E, DWP, and APS could be linked together to provide comprehensive coverage of the WSCC Southwest Region. Each utility may have to add PMUs in the field for sufficient coverage of its system.

BPA, SCE, and ETS developed tools for data management and analysis. The Stream Reader developed by ETS provides a real-time viewer as well as continuous data recording capability. This reader needs to be upgraded for the PDC exchange format. Four different data readers were developed to provide a variety of ways to display and analyze data, depending on what the user finds most useful. Several include the means to translate data into other formats, including MATLAB and ASCII, for analysis on other systems. A survey of what has been developed and how it can be obtained would be useful for future development of new phasor measurement systems.

2.5 Interutility PMU System Testing

Table 1 shows the events chosen for detailed analysis. Time is Pacific Daylight Savings time.

Table 1. Events for Detailed Analysis

Date	Time	Event
7/4/99	10:57	SRP Coronado Unit #2 tripped
7/7/99	15:41	Loss of Bell–Boundary line (NE Washington) with heavy import

The first event concerns a comparison of data transferred between PDC units. The event examined was a frequency deviation caused by the trip of SRP Coronado Unit #2. It caused a frequency deviation first detected by the PMU at San Onofre Nuclear Generating Station (SONGS) with a frequency trigger. It was detected at 10:57:25 at sample 27. It was then detected at Grand Coulee, in BPA, at: 10:57:26 at sample 16.

Figures 3 and 4, Appendix I, Section 1.4, compare data from the first disturbance transmitted between PDC units with the data recorded at the local site. The data was identical. The raw data from both incidents was examined in detail. The transfer had no time or data errors, proving the successful data exchange between the PDC units.

The second event in the table concerns a comparison of locally recorded versus exchanged data. In this incident, a lightning-caused line outage on the Bell Boundary line in Northeast Washington State triggered a remedial action scheme that dropped all boundary generation over 200 MW for system stability. Boundary generation went from 950 MW to 180 MW.

Figures 5 through 7, Appendix I, Section 1.4, provide more details about the data transfer and analysis using local versus exchanged data. They show the power system reaction to this sudden change.

The data obtained from a distant PDC using data exchange significantly enhance data measured locally. Data from a distant source can add an early warning or a record of concurrent and subsequent reactions. It has significant implications for monitor applications and, eventually, for remedial action schemes. Exchanged data is time correlated with local data as one measurement set. It is available on line for system, monitor, and controls as well as for analysis from recorded files.

3.0 Conclusions and Recommendations

The overall project objectives were to enable real-time monitoring and develop the potential for future control of the WSCC electric power grid using PMUs. Software and a system were developed to collect data from all major WSCC members and make it available to all participating members. The actual project outcomes are discussed below.

3.1 Project Outcomes

All objectives were met:

- Installed two PMUs, one at Mohave substation, the other at Kramer substation.
- Established communications links between the two PMUs and the PDC in Rosemead, California.
- Developed a software program, Disturbance File Reader, which allowed accessing and viewing of archived PMU data from desktop computers.
- Developed a software program, Stream Reader, which allowed viewing of real-time PMU data from desktop computers.
- Established an analog communication link between the BPA and SCE PDCs.
- Developed software that allowed the exchange of phasor data between the SCE and BPA PDCs.

3.2 Conclusions

Since completion of installation, data from these PMUs is accessible from desktop computers through the SCE network. Two software programs, the Disturbance File Reader and the Stream Reader, were successfully developed and tested. In addition, BPA and ETS codeveloped a PDC data exchange protocol that was tested, with positive results. ETS also determined the effectiveness of PDC data exchange utilities following an interutility disturbance. Results showed that data exchange could bring significant information from distant locations before changes are detected in local measurements. All research objectives were met.

3.3 Recommendations

The next step in using the results is for more companies to install PMUs and PDCs. Current PMU and PDC users publishing and sharing the technical information and benefits with utilities without PMUs can facilitate this. System reliability will be improved by widespread use of PMUs. For this project, PDC hardware and software were developed as customized products. The feasibility of using commercially available hardware and software for PMU applications should be explored. This will allow widespread use of PMUs in the electric utility system, providing more real-time data for better control and operation of the system. To date, most PMU data was used for post-disturbance system analysis.

3.3.1 Commercialization Potential

Both the Disturbance Reader and the PDC Data Streamer programs were successfully tested by BPA at its PMU lab facility. SCE and BPA use both programs on a regular basis. However, these programs are prototypes and are not commercially available. The programs were custom made

for this project and future efforts should include user input to upgrade them to commercial quality.

BPA presented the Stream Reader at the first PMU user group meeting in Portland, Oregon. Approximately 30 users from the United States and Canada attended the meeting and expressed interest in using this program.

3.3.2 Benefits to California

This project represents an important step toward improving the reliability of California's electricity and transmission-owning utilities. By facilitating real-time monitoring of electrical transmission and distribution systems, it allows the California Independent System Operators (CAISO) to monitor the voltage magnitudes and phase angles continuously from the substations where the PMUs are installed.

Real-time information is crucial for operators of the regional grid and CAISO. Continuous display of phasor information can be used to predict system stability in the event of a disturbance. Data exchange could also enable access to information from distant locations before changes are detected in local measurements.

3.4 Summary

The monitoring system developed supports the PIER objective of improving the reliability of California's electricity. The project's technical outcomes were as expected. The two software programs developed achieved the desired results.

Disturbance Reader allows system protection engineers and other utility personnel to view PMU archived data at their computers and allows storage and conversion in other formats for additional analysis. The PDC Data Streamer program enables the user to view the PMU data in real time and provides continuous data recording capability.

The project also provided engineering, construction, and successful testing of an analog communications link between SCE's PDC and BPA's PDC. A PDC data exchange protocol was developed and the test results were favorable. The PMU data exchange concept was successfully demonstrated using an analog communications link.

Future research should increase the PMU data exchange in real time between PDCs, which may require a digital communications link. In addition, future research should focus on determining the real-time data exchange needs, the communications media requirement, and emergency communications links, if primary communications media are unavailable. Future system developments should enable the use of PMU data for on-line applications such as load flow, stability, state estimation, and development of real-time nomograms to further enhance system reliability.

Appendix I– Section 1.4
Interutility PMU System Testing

Interutility Phasor Data Exchange

Introduction

This appendix provides the details of the establishment of interutility communications circuit between SCE PDC and BPA PDC.

In the 1980s, a Phasor Measurement Unit (PMU) was developed which implemented the concept of deriving phasor representations directly from voltage and current waveforms. In 1995, 21 PMUs were deployed in the Western Systems Coordinating Council (WSCC) system Extra High Voltage (EHV) as part of an experimental controls project. In 1997 the Bonneville Power Administration Laboratories developed a Phasor Data Concentrator (PDC) which combines the real time data streams from a number of PMUs into a single time correlated system measurement (Figure 1). This solved major problems of managing the system operation and the large quantity of data it produces. This still left a goal having a system-wide measurement obtained by combining the measurements from PMUs on the grids of different utilities. This goal requires setting up communications between utilities and implementing a secondary data stream between PDC units. The purpose of this contract is to develop this PDC-to-PDC communication ability, set up communications between Southern California Edison (SCE) and the Bonneville Power Administration (BPA), and demonstrate this data exchange capability.

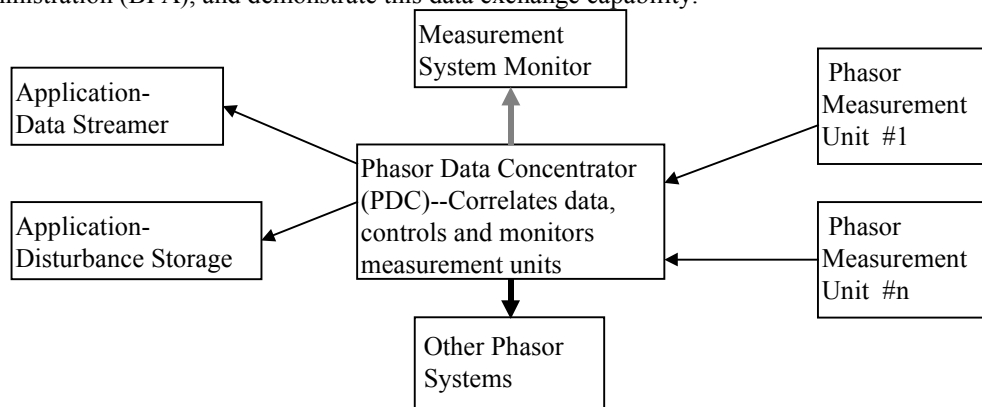


Figure 1. Local Utility (BPA, SCE) Phasor Measurement System

The original prototype PDC at BPA first became operational in June 1997. From that, a production unit was derived and became operational in late 1997, though it was not fully functional until June 1998. Data exchange capability between PDC units was implemented in the BPA Labs in early 1999 but was not fully operational until May 1999 (Figure 2).

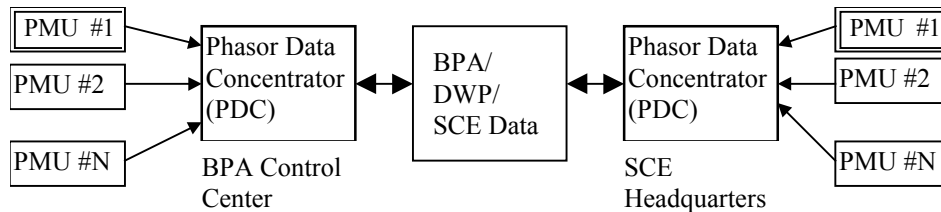


Figure 2. Phasor Measurement System with Data Exchange

Since SCE and BPA share no common boundaries, communications between them required negotiating a path through a third party. Los Angeles Department of Water and Power (DWP) graciously agreed to install channels on their existing paths to link BPA and SCE. Since the SCE-DWP link was all digital and the BPA-DWP link all analog, conversion equipment was required at DWP. Circuit problems at both BPA and DWP kept the circuit from being useable from January 1999 when it was first installed to June 1999, when the problems were finally all resolved.

Interutility Data Exchange Format

The data exchange format was defined and discussed in the course of Email exchanges and a meeting with ETS and SCE in 1998. It was further refined in early 1999 while the program was being written. Appendix C2 is the complete protocol description.

The PDC exchange protocol sends data between two PDC units. The format is similar to the IEEE format with modifications that account for the fact the data is from several PMUs rather than a single unit. Each message packet has two identifying sync bytes followed by a packet length count, time stamp, sample number, and count of PMUs represented in the packet. Next a data block from each of the selected PMUs is included and the packet is terminated by a checksum. Each PMU data block has the PDC status flag and the PMU status flag, the voltage phasor, one other phasor, the frequency, and the first digital status word. The two status flags are included so the data validity can be positively determined. The voltage phasor can be any phasor the user wishes to include, but will usually be the main bus voltage. The second phasor can be any other phasor, or an average of up to 4 other phasors. In this way an interchange current across several lines can be included. Frequency is a key measurement, and digital status can be used to immediately identify critical line outages.

The number of PMUs to include in the data stream will primarily depend on the communications bandwidth available. It is assumed that bandwidth will be limited to standard channel capability. (If it were unlimited, the full data stream could be exchanged using the streaming program.) Using the modem speed table, the user will choose the number of PMUs that will fit into the exchange bandwidth, choose which stations are the most significant in terms of system measurements, and then edit the configuration file to send the chosen data. When the system is started, it reads the configuration files and runs.

Data Exchange Monitor Summary

As with many R&D projects, technical difficulties prevented completion on the planned schedule. Communication problems were the principle problem. The communication channel starts at BPA on a long wire connection to BPA analog microwave. BPA microwave connects to DWP microwave in southern Oregon. At the DWP headquarters, the signal is translated from the analog microwave to a digital format on DWP digital microwave and sent to Mt Luekens. There it cross connects to SCE digital fiber optics, and travels to the PDC at SCE Rosemead. Data from SCE to BPA travels the same path in return.

Initially the system worked but was intermittent. With such a long system traversing 3 utilities and many departments, coordinated testing was a real challenge. Intermittent problems were first isolated to the BPA end wire connection. When this was resolved, the system was still intermittent. This was finally isolated to a bad channel unit at DWP and remedied.

In addition to communications, BPA found the hardware interface on the PDC would not support the high data transmission rates required by this application. This interface had worked well for receiving data at a high rate, but due to its architecture, would not reliably support high rate data transmission. This was resolved with more advanced hardware. However procurement lead times prevented upgrading the PDC system at SCE before the end of June.

The system has been run successfully for a continuous period commencing on July 1, 1999. For the purposes of this report, statistics have been computed on the period of July 1 through July 5. They summarize the performance and compare it with the communications links directly to PMUs at BPA. BPA has 8 PMUs that directly send data to their PDC. Seven PMUs send data via analog modems, six over analog microwave links only and one over both analog and digital microwave. One PMU uses a direct digital link over fiber optics.

For comparison, data is being presented that has been sent over a variety of communications systems. The table below summarizes the communication types. All results are presented in relation to receiving data at the PDC unit at BPA. Station identifies the remote end that communicates with the PDC at BPA. The symbol identifies the station on the next table of statistical results. The link with SCE is the only one between PDC units. The important difference is that data is sent both ways between PDC units simultaneously where links with PMUs only have continuous traffic from the PMU to the PDC. This should be adequately managed by the communications system, but could affect performance.

Symbol	Station	PDC Link	Communication Types
SCE1	SCE Headquarters	PDC-PDC	Analog modem, over digital fiber, digital microwave, analog microwave (2 systems)
COLS	Colstrip Sub	PMU-PDC	Analog modem, digital microwave, analog microwave (2 systems)
GC50	Grand Coulee 500 kV Sub	PMU-PDC	Analog modem, analog microwave (2 systems)
MALN	Malin Sub	PMU-PDC	Analog modem, analog microwave (1 systems)
BE23	Big Eddy 230 kV Sub	PMU-PDC	Direct digital, digital fiber optic

The PDC monitors the incoming data streams. It counts the number of good samples received on every channel. Dropouts are detected by checking that each channel has new data every 8.3 seconds. A channel is only marked as dropped out if it has no new data for 2 successive samples, and similarly, is only marked as restored when the data is good for 2 successive samples. Data can be lost up to 16 seconds without registering a dropout, so lost data will typically exceed dropout times. However, since modems can buffer data for several seconds, and the PDC exchange can buffer exchange data for nearly a minute, dropout times can exceed data loss. Also, during intermittent communication periods, the actual data samples checked may be gone while the remaining samples are there. This makes impression of greater data loss than actually happens; the reverse can occur also. Consequently, the total sample count is the best indication of data loss while the dropout figure indicates how the loss is distributed in time. Test totals: Time – 116 hr, 40 min; Number data samples – 12,600,000

Link Symbol	Number Dropouts	Total Dropout Time (M:S)	Percent Time Available	Number Samples Lost and Errors	Percent Reliability
SCE1	6	7:07	99.90%	11814	99.91%
COLS	6	1:42	99.98%	7708	99.94%
GC50	0	0:00	100%	872	99.99%
MALN	0	0:00	100%	1342	99.99%
BE23	0	0:00	100%	0	100%

Conclusions and Recommendations

Overall, the link is very effective. It operated reliably and accurately over the test period. It provides a dynamic system monitor for operations at both system control centers. It provides analysts with immediate access to system wide information which greatly facilitates timely problem analysis. Compared with most interutility data links, which send data only every few seconds to minutes, this system offers real dynamic wide area monitoring capability. Deregulation has forced a new era on power utilities. Groups that are separated from power production and sales now handle transmission. They are responsible for transmitting power from seller to buyer to the best of their ability. It has become more imperative than ever to manage the grid dynamically and over the entire interconnected area. It is important to not only be able to determine stability in real time, but to be able to assess security for last minute power exchange transactions. Traditional power measurements rely on measurement continuity to determine system state. Phasor measurements are unique in that a measurement from at a point isolated from other measurement points is very valuable for determining stability. This wide area phasor measurement exchange can provide a real time measurement from which both system stability and system state can be readily and quickly derived.

The data exchange format allows configuring the data exchange to fit the communications link capability. The communications link used in this test traversed fiber and microwave digital circuits as well as two long analog microwave circuits. Analog modems will automatically re-synchronize (“retrain”) with each other if the data error rate gets too high. When this happens, the normal data stream will be interrupted 1 to 20 seconds. To minimize these interruptions, the data rates on the modems were set low, and data from only one PMU was exchanged. Data from Grand Coulee was sent from BPA to SCE and data from Vincent was sent from SCE to BPA. Once communications problems are resolved, the link should support exchange of data from 3 stations each way.

The format is also fixed for two phasors and one frequency from each PMU (substation) as well as some status information. This format is experimental and was crafted on the basis of the earlier WSCC system test needs, basic stability measurement requirements, and implementation ease. In the future, there may be a need for more or fewer phasors per station as well as a reduced need for measurement status. This format includes type identifiers that will allow a modified format to be used by the same basic software. Once this has been tested for some time, improvements can be proposed and adopted.

This demonstration was designed to show that wide area exchange of phasor measurements could be made in real time with current technology and with acceptable reliability. It has been successful in not only establishing a data exchange link but demonstrating that it can run reliably and accurately. Several improvements should be considered. The biggest limitation is the data communications link itself. The current analog link at best will exchange data from three stations each way. If it follows typical patterns, analog links are much more prone to dropouts and impairments that require repair than digital links. With a 56-KB digital link, data from every station currently on SCE and BPA systems could be exchanged. This would give fairly comprehensive coverage of both systems, and a significant portion of the WSCC would be visible to both utilities.

The PDC itself is capable of simultaneous data exchanges with several other PDC units. Additional PDC units at PG&E, DWP, and APS could be linked together to provide a comprehensive coverage of the WSCC southwest. Each utility may have to add PMUs in the field for sufficient coverage of their systems.

BPA, SCE, and ETS have developed tools for data management and analysis. A stream reader developed by ETS provides a very popular real time viewer as well as continuous data recording capability. This reader needs to be upgraded for the PDC exchange format, which should be a fairly simple task. Four different data readers have been developed. They provide a variety of ways to display and analyze data, depending on what the user finds most useful. Several include means to translate data into other formats, including MATLAB and ASCII, for analysis on other systems. A survey of what has been developed and how it can be obtained would be useful for anyone developing new phasor measurement systems.

Analysis of Data Exchange Effectiveness Through Selected Disturbances

Due to the difficulty in implementing the data link, there was very little time to record and process data from system disturbances. Two events were chosen for detailed analysis. The first is a unit trip in the southern part of the WSCC system whose effects are detected by SCE measuring equipment before BPA equipment. The second is a line and generation loss in the northern part of the system nearer to BPA than SCE. Neither event resulted in any significant system disturbance—which is good—but both created a recordable incident with enough system reaction for analysis. Date/time is pacific daylight savings time.

Date	Time	Event
7/4/99	10:57	SRP Coronado Unit #2 tripped
7/7/99	15:41	Loss of Bell – Boundary line (NE Washington), 770 MW generation dropped by RAS

Comparison of Data Transferred Between PDC Units

The plots below compare data from the first disturbance transmitted between PDC units with that recorded at the local site. The purpose of this presentation is to demonstrate that data is being accurately exchanged and recorded with time stamp correlation. The raw data from both incidents was examined in detail and the transfer was found to have no time or data errors.

The first event examined was a frequency deviation caused by the trip of SRP Coronado Unit #2. It caused a frequency deviation first detected by the PMU at Songs with a frequency trigger. It was detected at 10:57:25 at sample 27. It was then detected at Grand Coulee at 10:57:26 at sample 16. Detection will usually be quicker near the source of the disturbance as it occurred here, though differences in setting levels can have a greater effect. The plots below validate data transfer from BPA to SCE and SCE to BPA.

The curve on the left was recorded at BPA and the one on the right at SCE. The data was transmitted from BPA to SCE over the data exchange. The curves are identical except they are offset. The offset measures .6333 seconds, which is equal to the difference in the file start times (19 samples/30 samples/sec). The curve recorded at SCE is shifted to the right by the 19 extra data points. When the files are shifted to precise time alignment, the plots match perfectly. The plots are shown here offset so both recordings are visible.

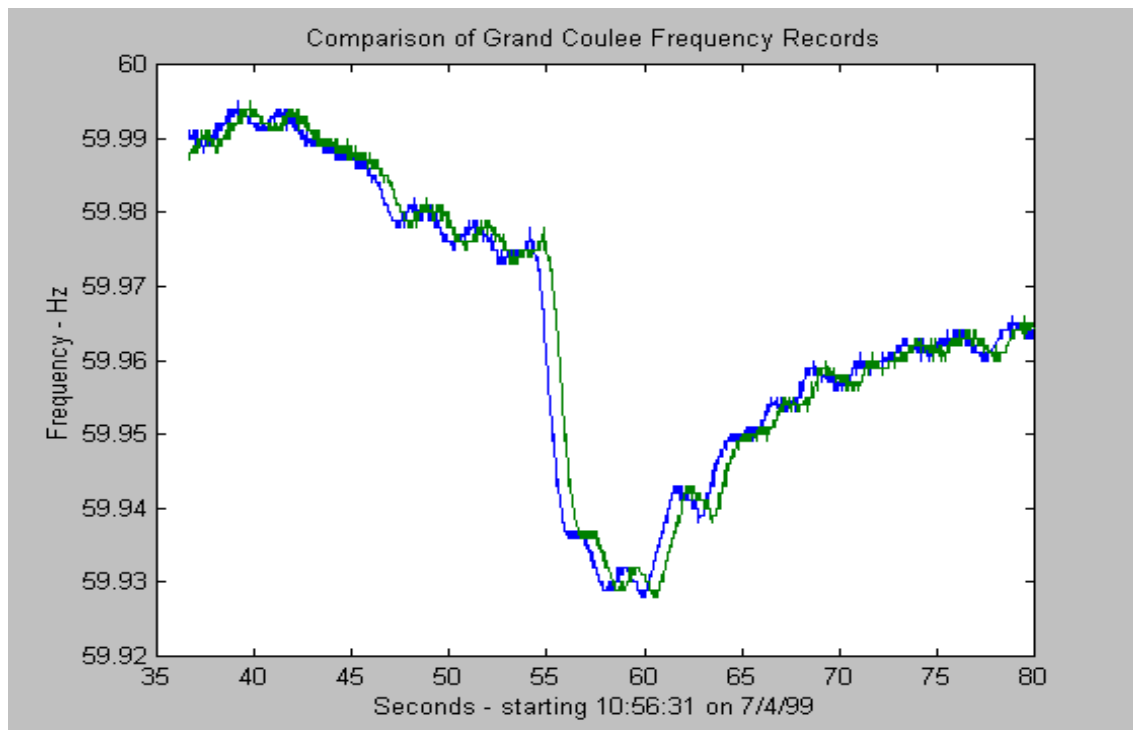


Figure 3. Detail of the Recordings of the Frequency Measured at Grand Coulee During the Disturbance

The upper curve was made at SCE and the lower curve at BPA of the same data. On this plot the time difference of .6333 seconds has been removed so they match perfectly in time. A 500 V offset has been added to the SCE recording to separate the curves; otherwise the curves are identical and appear as one curve.

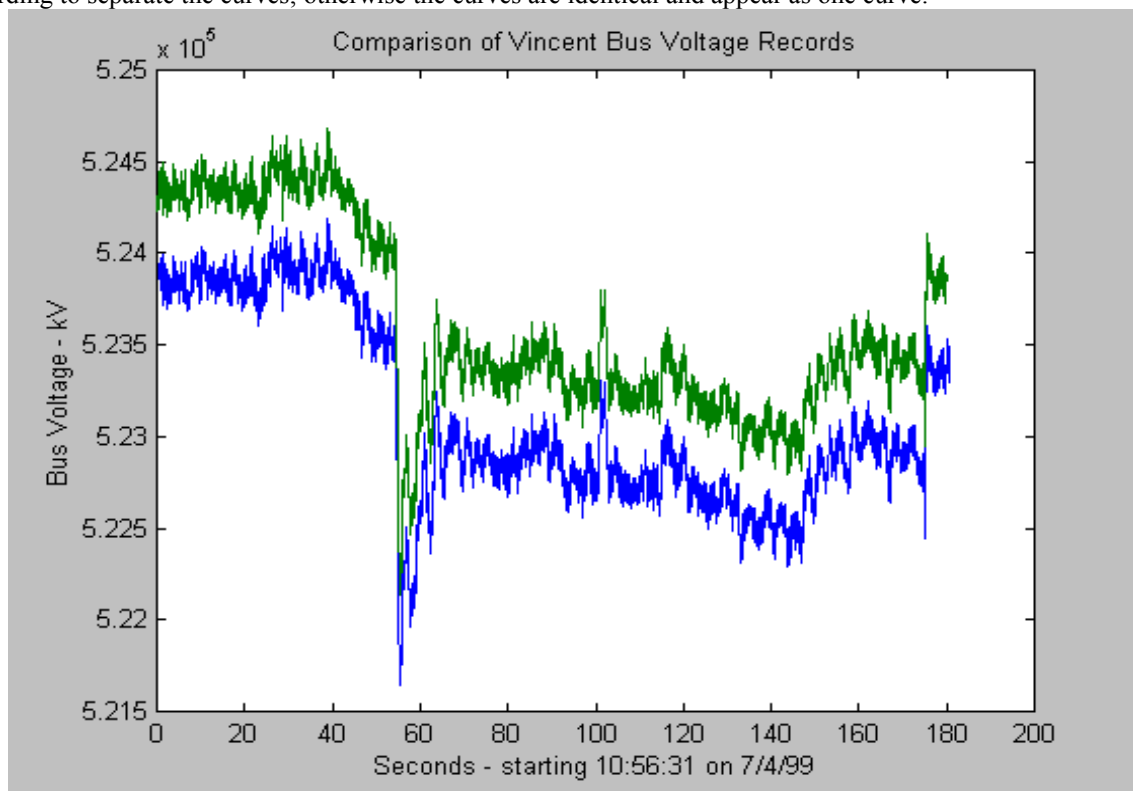


Figure 4. Recordings of the Vincent Bus Voltage

Comparison of Analysis Using Locally Recorded Only Versus Exchanged Data

In the second incident, a lightning caused line outage on the Bell-Boundary line in NE Washington State triggered a remedial action scheme that dropped all Boundary generation over 200 MW for system stability. Boundary generation went from 950 MW to 180 MW. These plots show the power system reaction to this sudden change. Figure 5 contains several linked plots from the recording at BPA that show some of the overall system reaction characteristics. The sudden dip in Grand Coulee voltage at the 52 second mark is due to the line fault itself. Plot b shows the phase angle between Grand Coulee and Malin and Vincent. The angle to Malin ramps up abruptly as the system power flow suddenly slows (as can be seen in plot c). The angle to Vincent has more of the typical NW-SW swinging reaction. System frequency in plot d is shown in greater detail in Figure 6.

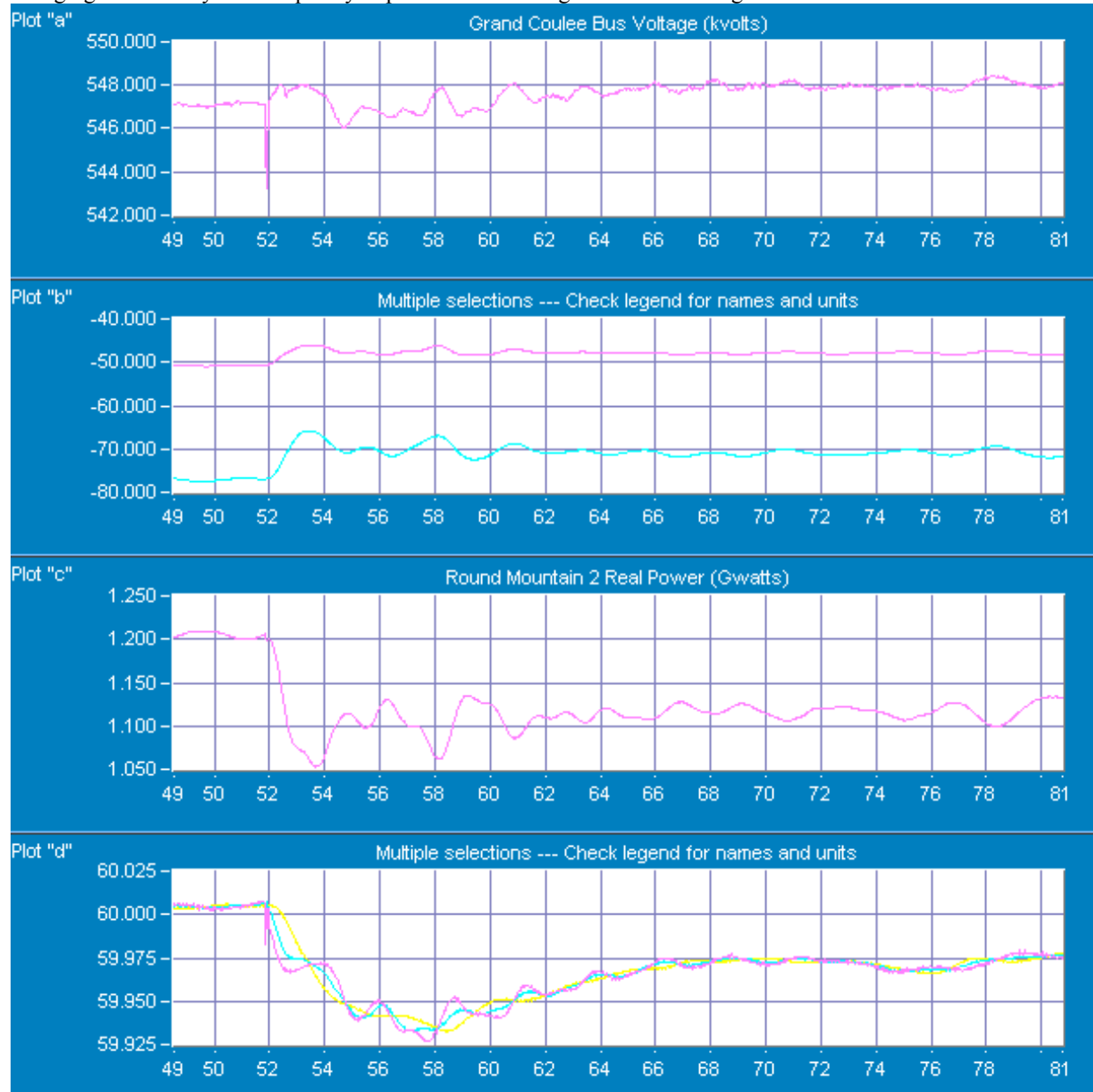


Figure 5. Multiple Plots from Boundary Outage. Plot a – Grand Coulee bus voltage. Plot b – Voltage phase angles, upper from Grand Coulee to Malin and lower from Grand Coulee to Vincent. Plot c – Power from Malin to Round Mountain on #2 line. Plot d – Bus frequency at Grand Coulee (magenta, furthest left at first drop), Malin (blue, middle), and Vincent (Yellow, furthest right).

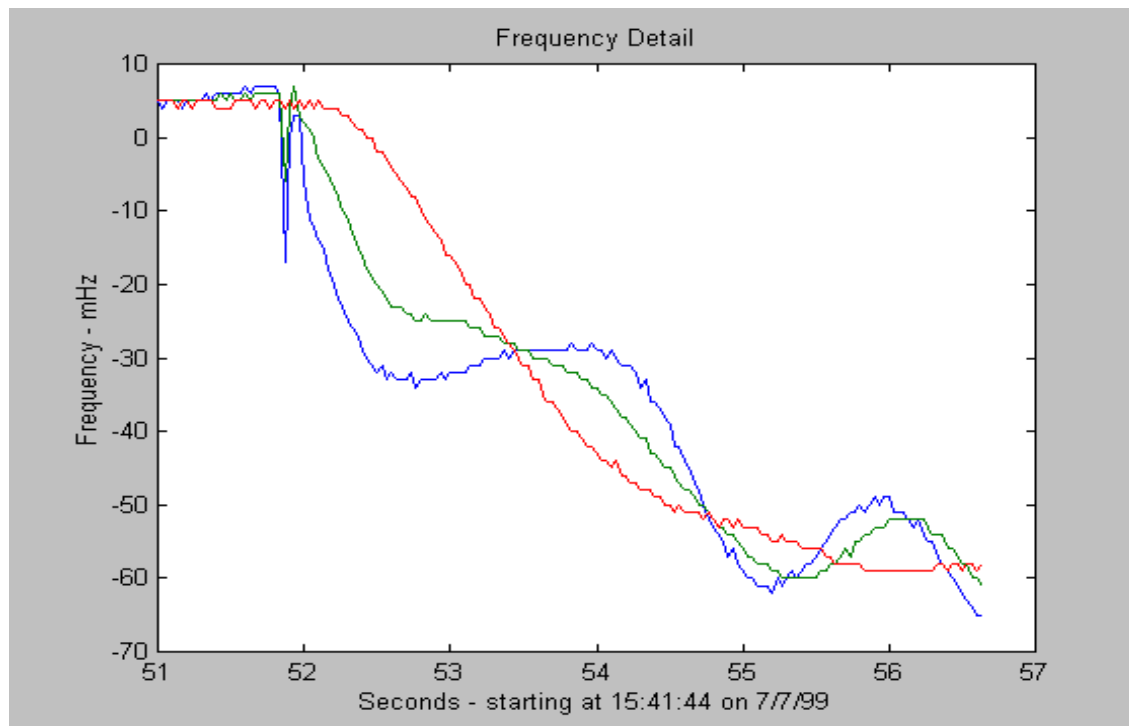


Figure 6. Frequency from Boundary Outage. Bus frequency (X1000) at Grand Coulee (blue, furthest left at first drop), Malin (green, middle), and Vincent (red, furthest right).

Figure 6 shows the frequency plots shown above in greater detail. Here the sudden spike at Grand Coulee caused by the fault is clearly visible. Grand Coulee frequency falls first followed by Malin and finally Vincent. There is about a .8 sec delay from the time Grand Coulee frequency falls 20 millihertz (mHz) to 59.98 Hz and the time Vincent reaches that level. Malin is about .5 sec ahead of Vincent at this point. Both Malin and Coulee have dropped 20 mHz before Vincent drops below 60 Hz. Given the data transit time of 150 ms on the PDC exchange (summarized below), there is .4 to .6 sec of early warning for control action.

The last plot in this series (Figure 7) from data recorded at SCE shows Coulee Frequency as transmitted to SCE with the Coulee-Vincent phase angle and the Songs-Santiago power. Frequency is a local measurement at Coulee, and it reflects the outage immediately. The system reaction is slower. As Coulee slows, the phase angle with Vincent drops. Finally power output from Songs picks up, providing more power to the local area to make up for diminished imports. Again the frequency dropped 15 MHz about .5 second before there is any reaction on the Santiago line.

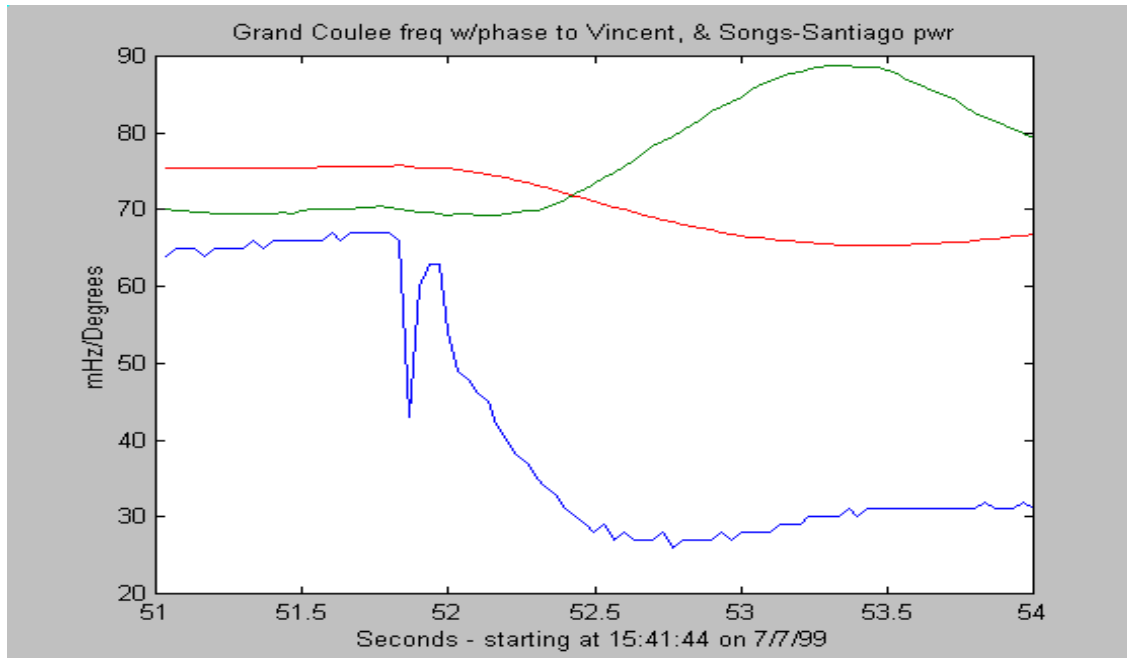


Figure 7. Combination Plot from Boundary Outage. Bus frequency (X1000) at Grand Coulee (blue, bottom), Coulee – Vincent phase angle (red, top), and Songs-Santiago power (green, middle), not to scale.

This section demonstrates that data obtained from a distant PDC using this data exchange significantly enhances data measured locally only. Data from a distant source can add an early warning as shown here, or a record of concurrent and subsequent reactions. It has significant implications for monitor applications as well as eventually for remedial action schemes. What is important is that the data exchange adds a system view, an aspect that is not usually available for local operations. Exchanged data is time correlated along with local data as one measurement set. It is available on line for system monitor and controls as well as for analysis from recorded files.

Data Exchange Transfer Delay (Time)

The time from the instant an event occurs until the information reaches another processor in a useable state is called measurement latency or delay. Delay in data recording for studies or file transfer is of no concern; all that matters is that the data arrives intact. Delay in any kind of monitoring or control must be accounted for and managed. For a monitor observed by humans, delays less than 0.01 seconds are usually imperceptible. Monitors used for human intervention must be tailored for the use: a generator sync scope needs a delay within 0.1 seconds while a SCADA switch monitor can be used with several seconds of delay. Control systems generally require much tighter limits on delay. If phasor measurements are going to be used with monitor or control systems, the delay needs to be quantified.

At least three studies have quantified the response required for control action in the WSCC, which use phasors for the primary measurements. Each of these was for a specific type of control and was tested extensively on the WSCC system model or an appropriate reduction. The first two were not implemented, but the third is still under development and is planned for deployment in 2000. These studies are summarized in Appendix C.2.2. The net result of these studies is that communication times for control actions must be limited to four to six cycles. Though that may be the ultimate goal for real time controls, there are many other remediation schemes possible using longer delays. This study is the first attempt to quantify these delays with an actual operating data system. This provides a baseline from which we can either proceed to implement controls or work toward improvement so we can implement controls.

Three plots are presented below to give some idea of what the phasor measurement delay time looks like. They show the measurement delay time from when each sample is transmitted from PMU until it is placed in the PDC data buffer. The PMU samples precisely with GPS time sync and transmits the samples within 500 microseconds of the measurement time (typically in tests). The PDC records the arrival time for every sample using a precision GPS synchronized timer. The arrival time compared with measurement time is shown in these plots. These are typical examples—not the best or worst—taken from many tests.

It has an average delay of 93.4 milliseconds with a typical delay ranging from 85 to 98 ms. There are a couple dips, probably due to the communication system. Outliers up to 114 ms are probably created by random time slicing in the PDC. Modems sending a longer message, like John Day, have a longer latency due to the longer message length. Units with a shorter communications path, like Keeler, are a few milliseconds less. The results are summarized in the table below.

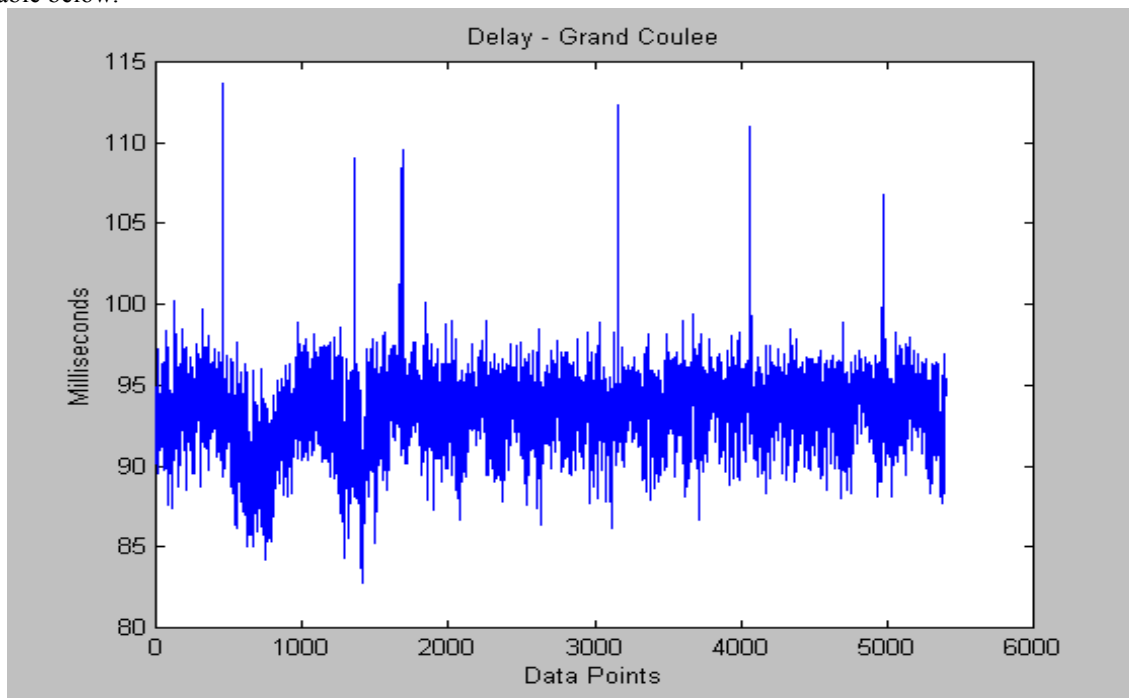


Figure 8. Measurement Delay Time for Analog Modem Link

It has an average delay of 38.8 ms, less than half that of modems. It shows a strong patterning in delay time due to processing in the fiber system. It is observable on an oscilloscope. The occasional outliers up to 55 ms are also apparently due to time slicing on the PDC. Overall, the performance of this link is superior to the analog modem links.

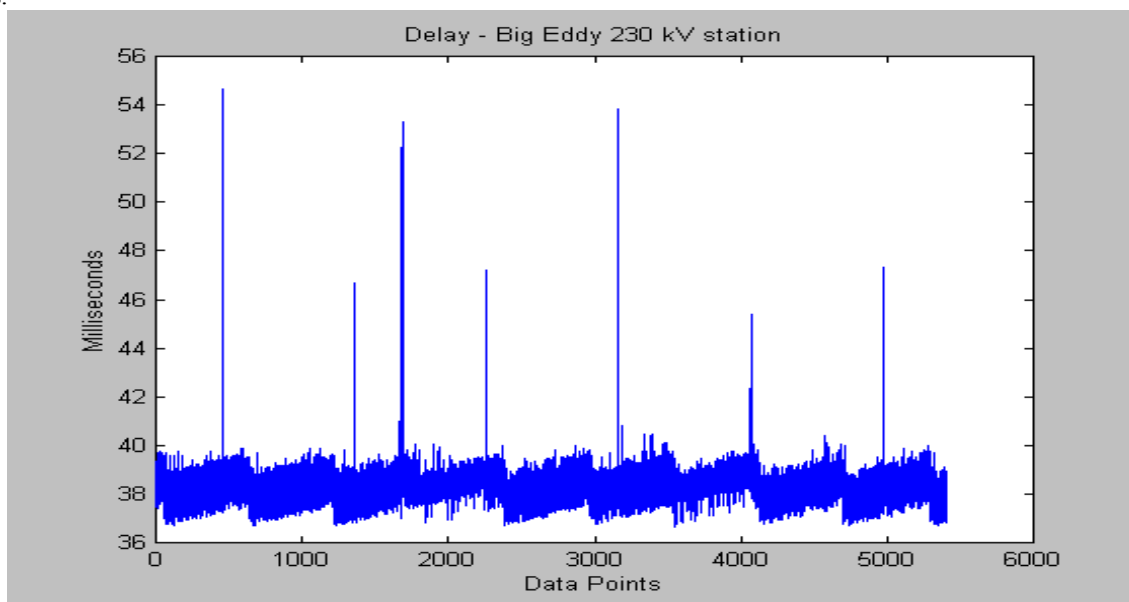


Figure 9. Big Eddy 230 Uses a Direct Digital Path Over Fiber Optics

This link includes the delay from the PMU units to get into the PDC data buffer, the delay to be read out of the buffer and re-transmitted, and then the delay through analog modems over one analog and two digital links. The SCE links into their PDC are digital (fiber) so probably average around 40 ms (as does BPA's fiber link). Modems over a long path like this typically require around 90 ms. The average of 151 ms thus indicates it takes about 20 ms to get all the data in the buffer for a certain sample, read it, and send it. There are again a few outliers, though these could be due to both time slicing delays on the transmit PDC as well and on the receive PDC.

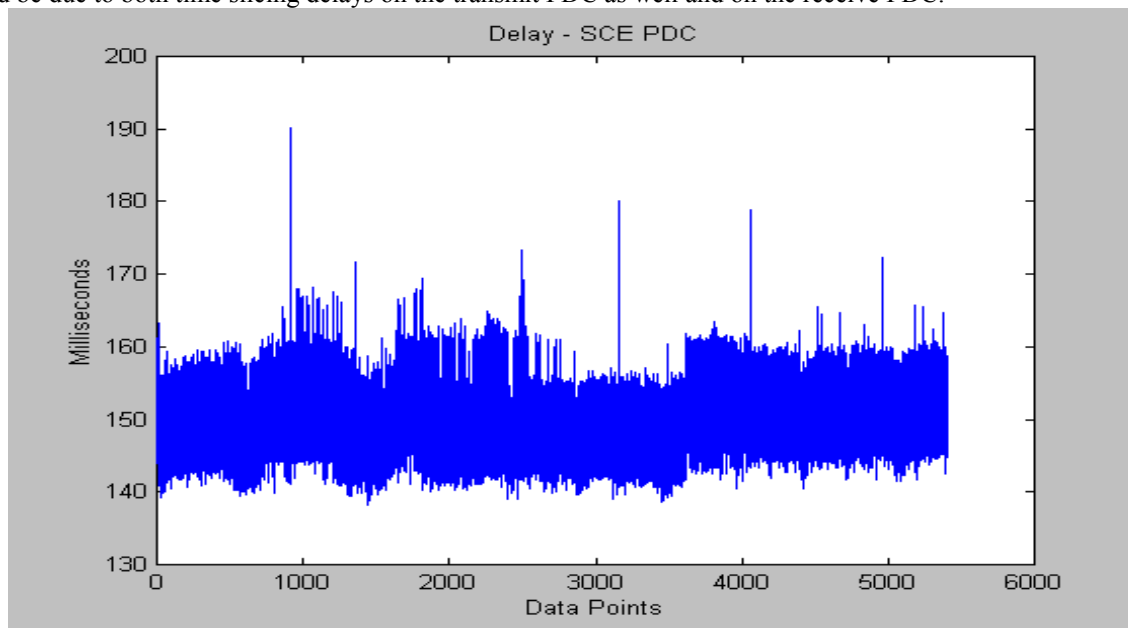


Figure 10. Delay on Data Link With SCE

Time of arrivals: Time delay from measurement until data is in PDC buffer

Time in milliseconds

Station	Mean	Std Dev	Min	Max	Type
Grand Coulee	93.39	2.29	82.72	113.63	Analog Modem
John Day	105.97	5.00	99.27	141.76	Analog Modem
Malin	94.71	2.81	81.56	114.07	Analog Modem
Colstrip	95.17	2.59	84.37	114.25	Analog Modem
Big Eddy 230 kV	38.34	0.97	36.65	54.67	Fiber
Big Eddy 500 kV	85.20	2.51	78.84	112.20	Analog Modem
Sylmar	91.94	4.75	85.00	222.80	Analog Modem
Maple Valley	83.38	3.47	76.01	183.50	Analog Modem
Keeler	90.31	2.50	80.45	104.72	Analog Modem
SCE data exch	150.77	6.36	138.19	190.14	Analog Modem/fiber

Overall it is apparent these systems would not meet time requirements of the WSCC studies summarized here using analog modems for data communications. With direct digital transmission (such as fiber), the control criteria can be met. The PDC may need to be fine tuned to reduce the number and size of the data outliers. The data exchange is too slow for these controls, though with all fiber connections and fine tuning it could yield six to seven cycle performance. It has been very informative to make these measurements with great precision to find out what is actually going on at the lowest level.

Two additional tasks are needed to fully characterize time performance of this system. The time from an actual power system event occurrence until the phasor data reflects the change needs to be quantified. This can be estimated from the PMU processing algorithms, but should be measured in actual tests. This task is needed for each different type of PMU, as different measuring algorithms may yield different results. The second task is to measure the latency in the real time data stream (Ethernet) out of the PDC. Data transmitted in the data exchange shows the PDC re-transmission is fast, but Ethernet delays will be different than those over serial. There will also be variations

in the data receiving equipment, so this test should be performed in relation to the application that is the end user of the data. These two latencies combined with that of the PDC presented here will give a complete performance picture for monitor and control applications.

Conclusions

Data compared from both ends of the data exchange illustrate the effectiveness of the system. It will be enhanced by the addition of more points in the exchange. Once the communications are proven stable, the data rate is increased to include 3 PMUs (stations) each way. The system could be enhanced by upgrading the link to 56 KB digital. As it stands, the principal system bus voltages and phase angles for the NW intertie and the LA basin are present.

The timing study shows the system in its present implementation can be used for monitoring systems and certain control actions, but not for first swing remedial actions. Probably the most useful developments are dispatch displays of WSCC state and on-line state estimation. A real time display of key WSCC bus voltages, phase angles, and power interchanges could effectively convey overall system state to system security monitors, dispatchers, and SCADA operators. It could include highlights of problem areas. It would also be a great tool to assess the current system state after a major event, such as the loss of a large generator or tie line. Such a system could be fed by a single PDC unit using exchanges with other PDC units for wide area data, or could infeed the high speed data streams from several PDC units directly using wide band communications.

State estimation using phasor measurements integrated with other measurements is also recommended. Phasor measurements provide state information directly. They can be used to increase accuracy of systems currently in use where the area is well covered with SCADA systems. They can increase system effectiveness by providing state of neighboring systems where little information is available. Several efforts have been undertaken to integrate these diverse data systems, but each system is typically part of an EMS and must be done on a per system basis.

Most power system dynamics can be detected at a few key measurement points. While most studies point toward many measurement points, experienced engineers working with a real system will first examine data at a few stations to determine system response. Power system configuration and actual events may then shift attention to other stations. The Western utilities can build an effective dynamic control tool by building on this concept. SCE and BPA have phasor measurement points at most of the key stations within their grids, and this exchange to supplement local data. These measurement systems are effective dynamic monitor and control tools as they stand now, and will only improve as more stations and data links are added.

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Appendix B.2.1 – Phasor Data Exchange Protocol

Basic Message

This format is fairly simple to implement. It uses a fixed synchronization character (AAh) at the start for simple sample separation. The message ID may be used in the future to designate other types of packets, such as packets that contain 3 or 4 phasors from each PMU, but here is fixed and can be used as a secondary sync byte (CCh). Count will be fixed once the packet size has been determined, but can be used to simplify reading the data stream. Time and sample numbers appear as in the synchrophasor standard, and give the data sample an absolute time reference. PMUs available and the communications bandwidth determine the number of PMUs. A table below summarizes data transmission rates and the number of PMUs that can be included for a given bandwidth. The data from each PMU is fixed to a minimal status subset, 2 phasors, frequency, and one digital status word as described below. The first phasor is as sent by the PMU; the second may also be as sent or may be the sum of up to four phasors. Typically the first phasor will be the station bus voltage and the second will be a line current or the sum of several line currents. The checksum is a 16-bit checkword (2 byte checksum).

Data Frame

Header	Count	Time	SAMPNO	pmuNO	PMU 1	PMU 2	...	PMU n	Check
2 bytes	2 bytes	4 bytes	2 bytes	2 bytes	16 bytes	16 bytes		16 bytes	2 bytes

Description:

Header	Byte 1	Sync byte, AAh
Byte 2		Message identifier (CCh)
Count	1 Word	Total number of bytes in packet, 16-65535
Time	1 LongWord	Time stamp for entire packet, in sec, NTP format
SAMPNO	1 Word	Sample number as stored in table, numbered 0-(N-1) where N=table data rate
pmuNO	1 Word	Number of PMUs carried in packet
PMU i	x Long Words	Data for each PMU corresponding to time stamp. Data includes info including validity flags, phasors, frequency, and digital
Check	2 bytes	16 bit check word, computed by an XOR of every word in the packet (except the checksum itself) starting with the Header.

Data Frame Size: 14 bytes (overhead) + 16 bytes/PMU

Individual PMU Data Format

Data format is exactly the same for all PMUs. Only the first phasor (bus voltage), one more phasor (selected by user), the frequency, and the first digital status words are sent. The first 2 bytes of the PDC Channel info contain the receive status and data validity tag. The second two bytes are the PMU status word as sent from the PMU. Two phasors 4 bytes each follow. These may be in complex rectangular format or polar format as described in the IEEE SYNCHROPHASOR Standard. Currently all systems in the WSCC use the 16 bit integer rectangular components. Choice of these phasors is up to the user. Typically the first will be the station bus voltage phasor and the second will be a selected current or a composite of several currents. The frequency is the offset from 60 Hz in milliHertz. The 16 bit digital status can be used for any binary representation such as breaker position or reactive insertions.

Chan Info (Part)	STAT 1&2	PHASR1	PHASR2	FREQ	DIG 1
2 bytes	2 bytes	4 bytes	4 bytes	2 bytes	2 bytes

Data Rates

The data rate resulting from the above format must be within reasonable modem capability. Most modern modems will adjust their rates according to channel quality. Generally the higher rates require higher quality, though this is not a linear function. Further, as modems improve, so does their ability to transfer at a given speed over a given channel quality. Modems typically come in 14.4, 28.8, 33.6, and most recently 56 KBPS. It is best to limit actual

data rate several steps lower than the nominal modem rate to allow successful operation even in sub-optimal conditions. To this end, the rates calculated below are limited to the given limit speed. This puts constraints on how many PMUs from each PDC can be included in an exchange utilizing a certain data rate. A direct digital link can carry data at the full channel speed without degradation.

Assumptions: Data will be exchanged at the rate of 30 samples/second
 A 'frame' is one complete packet as described above
 Data will be sent in 10 bit words containing one data byte (8 bits), so the data rate in bytes is exactly 1/10 the transmission rate in BPS

Overhead/frame: 14 bytes

Overhead/sec: 14 bytes X 30 frames/sec = 420 bytes/sec

Payload/PMU: 2 Phasors – 16 bytes/PMU

Payload/PMU/sec: 2 Phasors/PMU – 16 bytes X 30 frames/sec = 480 bytes/sec

Modem Data Rate		Allowable Number of PMUs	Actual Data Transmission Rates	
Rated Speed	Limit Speed		Number of PMUs	Actual Rate (KBPS)
14.4 KBPS	12.2	1	1	9.0
			2	13.8
			3	18.6
28.8 KBPS	24.0	4	4	23.4
33.6 KBPS	28.6	5	5	28.2
			6	33.0
			7	37.8
			8	42.6
56 KBPS	48.0	9	9	47.4
			10	52.2

Appendix B.2.2 – System Control Data Timing Studies

At least three studies have quantified the response required for control action in the WSCC which use phasors for the primary measurements. Each of these was for a specific type of control and was tested extensively on the WSCC system model or an appropriate reduction. The first two were not implemented, but the third is still under development and is planned for deployment in 2000.

The first of these was a study to determine if stability at the Colstrip generation plant in Eastern Montana could be maintained with reduced intervention by using phasor measurements [1]. Phasors at Colstrip would be compared with those from Grand Coulee, which represents the Western end of the tie line. Studies indicated measurements would have to be made, transmitted, and compared within 7 cycles (117 ms) after fault clearing to be effective. This is well within the capability of phasor measurements communicated between the PMU and the PDC which only involved one communications link. Integration of the relay function with the PDC is necessary to speed the transfer of information into the controller.

The second was an EPRI sponsored study of using phasor measurements throughout the WSCC to control the DC links to the LA area to control first swing stability [2]. This deployment of PMUs provided the basis for the present system at BPA and SCE. The plan was that if measurements indicated an event that could result in inter-area instability, a momentary ramp would be applied to the Intermountain or Pacific NW-SW DC link that would damp the first swing. This would give other controls time to act and restore power balance. This study only evaluated the effect of this one control action and presented the number of unstable cases that it would stabilize. Generally, a faster control action stabilized more cases. However, control actions taken within 6 cycles (100 ms) or less were all about equally effective. This plan also required knowledge of the current system configuration. That is, the system will respond differently under various depending on what lines are in service. Consequently, the controller needs up to date information of line status. The status word included in the exchange data message can be used for breaker and switch position, which determines line status.

The third study is ongoing and these are intermediate results [4]. This study is for an advanced voltage control, which uses phasors for measuring bus voltage levels [3]. The previous two studies focused particularly on the phase angle aspect of phasor measurements; this one uses the high resolution, low noise aspect of the measurement technique. This system will insert capacitors if voltages begin to collapse. While this phenomenon is normally fairly slow, it can occur rather rapidly on an intertie line with a sudden loss of reactive support. Studies show that with this remedial action, power transfer on the Pacific NW-SW intertie can be increased 50-100 MW. For this result, phasor measurements must be communicated within 4 cycles (67 ms), although there is a further allowance of 10 cycles for measurement and processing. Since this study required only local measurements on the BPA system, delays with the inter-area data exchange are not a concern. However, if the interarea data exchange may be used for future expansion of the voltage controls, delays measured by this test will have to be taken into account.